Fuel cells can buy AI data centers time, if the site is ready.

Modular generation can bring usable power forward when gas, permissions and site works are ready. Industry commitments include frameworks; manufacturing capacity is not installed generation. In Korea, auction and direct-trading routes have different eligibility and commercial conditions. The comparison is dependable delivered power at a defined site.

3–6 years

Rystad Energy's 2026 estimate for a large US load; a site-specific connection clock

9 GW

Industry fuel-cell commitments including frameworks, June 2026; not all firm or installed (Rystad Energy)

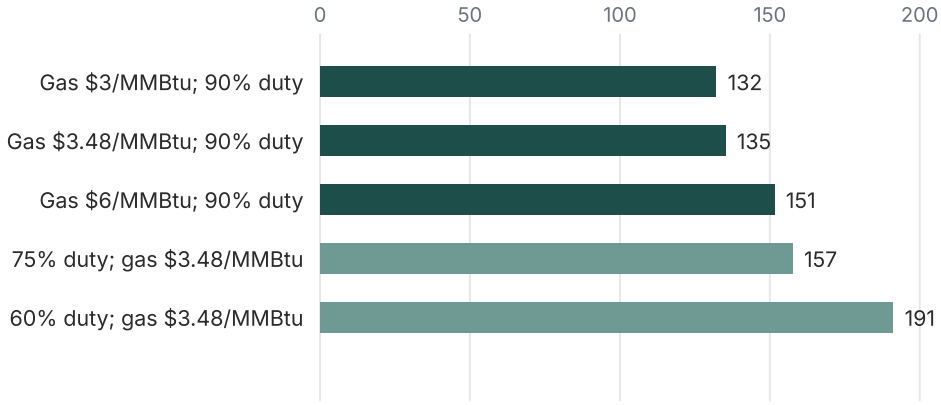
$135/MWh

Illustrative generation cost before excluded site and lifecycle costs; 90% running, no credit (NRG calculation)

SUMMARY

Earlier power has value; the buyer's cost and revenue bases must match.

One variable changes at a time. Fuel basis and duty are assumptions, not observed site ranges. Same generation-cost model, no credit; exclusions on the cost page.



Illustrative US$/MWh, before credit and exclusions

Source: EIA AEO2026 planning inputs; October STEO; NRG calculation

The IEA estimates 485 TWh of global data-center electricity use in 2025 and projects about 950 TWh in 2030. DOE/LBNL's 2025 Update, released June 2026, replaces the earlier US study; its 2030 reference is 649 TWh, within compounded-uncertainty scenarios of 521–843 TWh.

Rystad gives large US loads a 3–6-year grid wait. Enverus's modular-project comparison gives 18–24 months. Equipment delivery or installation on a prepared site is a shorter, different clock from full-site commercial operation.

Rystad's 9 GW fuel-cell aggregate includes frameworks. Dividing by its 1.8 GW annual manufacturing metric gives five years of equivalent output, not a delivery lead time or proof that every commitment will be built.

The cost model gives about $135/MWh, or $103 if an assumed 30% credit is fully realized on the modeled basis. It excludes additional stack changes, redundancy, degradation and site/fuel connection costs. The national grid average is not a site tariff.

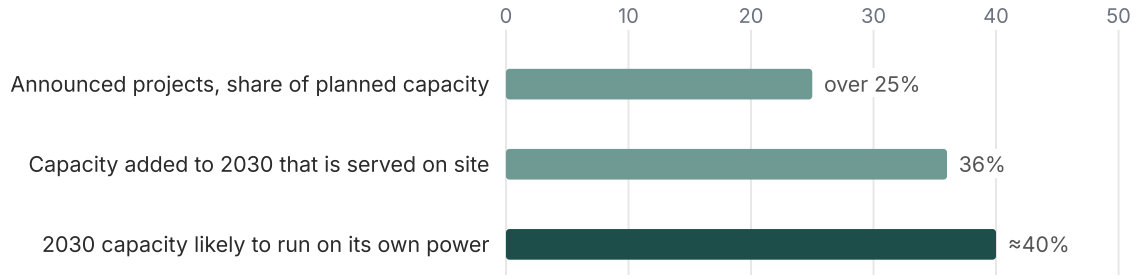
The sensitivity graphic keeps generation capacity on one basis and varies fuel or running separately. It makes no gross-revenue or profit comparison. IT load, facility overhead, reserve generation, earning utilization and the party receiving AI revenue still matter to a buyer's economics.

Korea's 2026 general-hydrogen round offers 930 GWh a year; designated-zone direct trading is a separate conditional route. Neither annual auction energy nor factory capacity measures campus power available today.

On-site power forecasts measure different populations and project stages.

Planned capacity, new load additions and total future capacity are separate denominators. The estimates signal interest; they do not form a common adoption range or measure operating SOFC penetration.

Different measures: Cleanview announced plans; Enverus new US load additions, 2026–2030; Rystad total US capacity, 2030. Do not average.



Source: Cleanview (mid-2026); Enverus (2026); Rystad Energy (June 2026)

Cleanview's mid-2026 report counted about 90 GW at 59 data centers, with 92% of projects announced since early 2025. Its 25% share concerns announced planned US capacity. Only 2.2% of the tracked on-site capacity was operating then. Announcements are not energized load.

Enverus expects on-site plants to serve 22.5 GW, or about 36% of new US data-center load additions over 2026–2030. Rystad's roughly 40% concerns projected total US capacity in 2030 likely to pursue dedicated on-site generation. These stocks and flows cannot be combined.

The IEA's April 2026 analysis puts on-site supply at 6–13% of US data-center load growth under its scope. That lower estimate has a different demand and generation definition; it is a reason to examine assumptions, rather than average forecasts into one range.

A supplier-sponsored January 2026 survey, fielded in November 2025, covered 152 respondents across industry roles, 84% US-based. Hyperscalers and colocation providers answering the fully-on-site question (n=92) expected roughly one-third of US sites fully on-site in 2030, on average. A separate developer question (n=92) put 73% in the actively evaluating on-site power category. These are question-specific expectations and intentions, not installations. NRG tracks announced, contracted, shipped and operating stages separately.

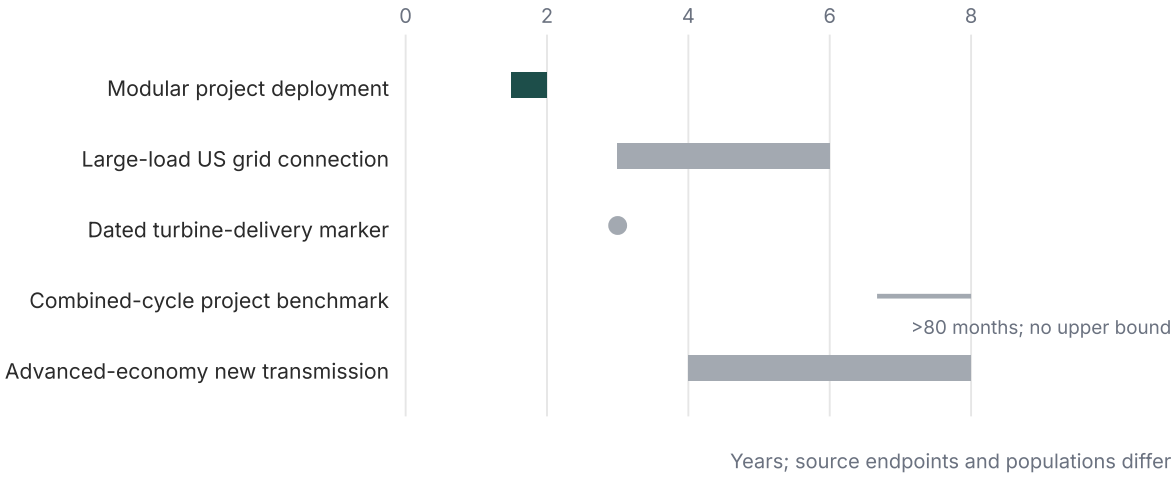
> **2.2%**
>
> Operating share of Cleanview's announced on-site capacity in its mid-2026 snapshot. A dated snapshot, not a November operating census.

Sources: Cleanview (mid-2026); Enverus; Rystad Energy; IEA (April 2026); supplier-sponsored 2026 power survey

A complete modular project has a different clock from equipment delivery.

Enverus's 18–24-month modular deployment estimate is a project comparison. A module arriving at a prepared site does not establish when a new campus can reach commercial operation.

Different clocks: project deployment, equipment delivery, grid connection and transmission construction. Ranges are source estimates, not site commitments.



Source: Enverus (August 2026); Rystad Energy (June 2026); IEA (2025); dated company delivery marker

Rystad Energy finds that connecting a large load to the US grid now takes 3–6 years, about three times as long as in 2015. JLL puts the average wait in the main data-center markets at more than four years, and the IEA estimated in 2025 that grid constraints could delay about 20% of the data-center capacity planned to 2030.

New transmission is a separate task: the IEA's 2025 benchmark is four to eight years in advanced economies. An October 2026 Korean press report gives about nine years for a long overhead line, but about four for a shorter underground case. Neither duration is the wait for every individual connection.

Heavy-duty turbine delivery and a complete gas plant are different milestones. A dated company marker puts delivery around three years; Enverus's August comparison describes more than 80 months for combined cycle and 18–24 months for modular technologies. Size, scope and site preparation matter more than treating these as guarantees.

Equipment availability, installation and commercial operation must be recorded separately. Gas service, permit applicability, transformers, switchgear and testing remain project conditions. The IEA's October 2026 policy supplement warns that grid integration remains a distinct challenge; it does not replace April's demand outlook.

> **1–4.5 years**
>
> Illustrative bridge envelope from subtracting independent source ranges: 3–6 years for grid connection less 18–24 months for modular deployment. No joint probability or site promise (NRG calculation).

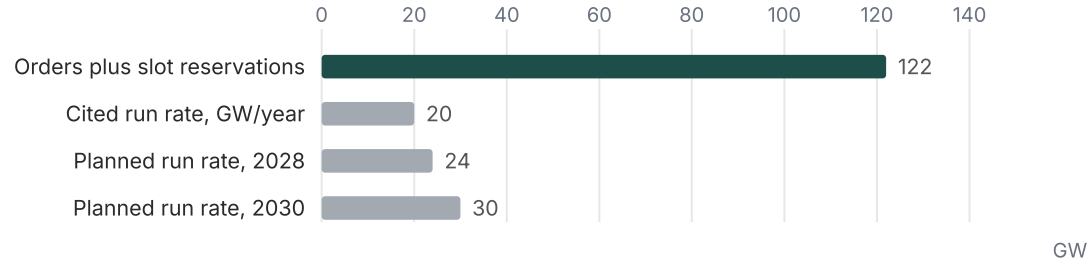
Sources: IEA (2025); Rystad Energy; Enverus; JLL; Metro Seoul; company filings (2026); NRG calculation

03 · THE TURBINE QUEUE

A mixed turbine book equals six years at a cited manufacturing run rate.

September 2026 orders and reservations total 122 GW. The cited 20 GW annual run rate is a manufacturing measure; planned 24 GW in 2028 and 30 GW in 2030 are not delivered output today.

Mixed book in GW versus annual manufacturing run rates in GW/year; arithmetic equivalence is not lead time.



Source: company filings and announcements

The mixed book is equivalent to 6.1 years at 20 GW a year, or about five at the planned 24 GW rate (NRG calculation). It is not a delivery schedule, an estimate of shortage duration or a claim that all production serves data centers.

A slot reservation holds a place in the factory schedule before a firm order is signed. In the third quarter the maker turned 13 GW of reservations into orders, signed 8 GW of new ones and shipped 5 GW of equipment; at the end of September, 58 GW of its 122 GW were still reservations. The remainder is orders; reservations and shipments must not be added as independent demand. A new buyer still needs a negotiated delivery date.

The maker expects at least 130 GW of commitments by end-2026. In April 2026, it described roughly three-year heavy-turbine lead times; an April report tied about a fifth of its then-contracted 100 GW to data-center load. These are dated observations, not a November delivery offer or a measured share of the September book. The IEA counted a 70% rise in 2025 in gas-turbine orders meant for data centers.

The maker's chief executive argues that over a three-year project the turbine is often not what sets the date; the rest of the plant is. Lazard's 2026 study adds that turbine supply is constrained and has stretched development timelines well beyond historical norms.

Other markers of the turbine queue

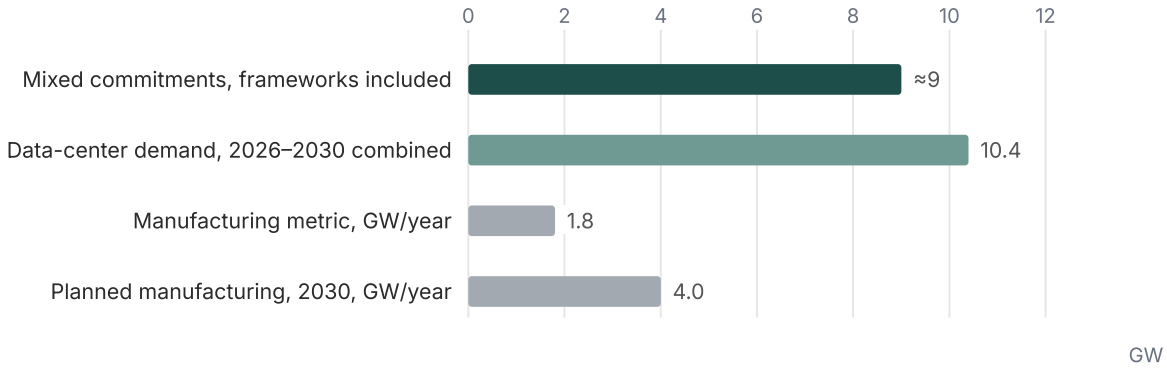
Marker	Reading	Source
Largest maker's slots left for 2029–30	About 10 GW	Power Engineering, Apr 2026
Combined-cycle cost in Lazard's 2026 study	$1,450–2,100 per kW	Lazard, Jul 2026
Combined-cycle quotes, plants due after 2028	$2,400–2,600 per kW	Lazard, Jul 2026

Sources: Company filings; Power Engineering; Lazard; IEA (2026); NRG calculation

Fuel-cell commitments and manufacturing capacity are different stages.

Rystad's June 2026 industry book includes about 9 GW of contracts and frameworks. Its 1.8 GW annual manufacturing metric and planned 4 GW in 2030 describe supply capability, not independently verified shipments.

First two bars: GW of mixed commitments and cumulative demand. Last two: annual manufacturing metric, GW/year. Source stages differ.



Source: Rystad Energy (2026)

A framework sets a ceiling rather than requiring every purchase. Dividing the 9 GW mixed book by the cited 1.8 GW annual metric gives five years of equivalent output (NRG calculation). It does not locate an individual order in the schedule or establish the firm share of the book.

Rystad projects 10.4 GW of cumulative data-center fuel-cell demand over calendar 2026–2030. Demand is not installed generation. A factory may serve other uses, hold inventory or ship equipment before a site is ready; yield, scheduling and commissioning affect the conversion.

The same release puts fuel-cell market revenue near $30bn in 2030 against $2.8bn in 2025. Its public wording does not resolve a data-center-only systems denominator, so this report does not compare it as such with whole-SOFC forecasts. The paid model was not reviewed.

Rystad's 20–25% projected SOFC system-cost decline by 2030 is a model assumption, not a current quotation. Manufacturing plans can reduce constraints only after capacity becomes saleable production and projects can accept it. NRG therefore separates framework, firm order, factory shipment, commissioned generation and load actually served; none of those stages can be inferred from the headline book alone.

> **2.25 years**
>
> Equivalent output for a 9 GW mixed book divided by a prospective 4 GW/year manufacturing rate. This is arithmetic, not a delivery forecast (NRG calculation).

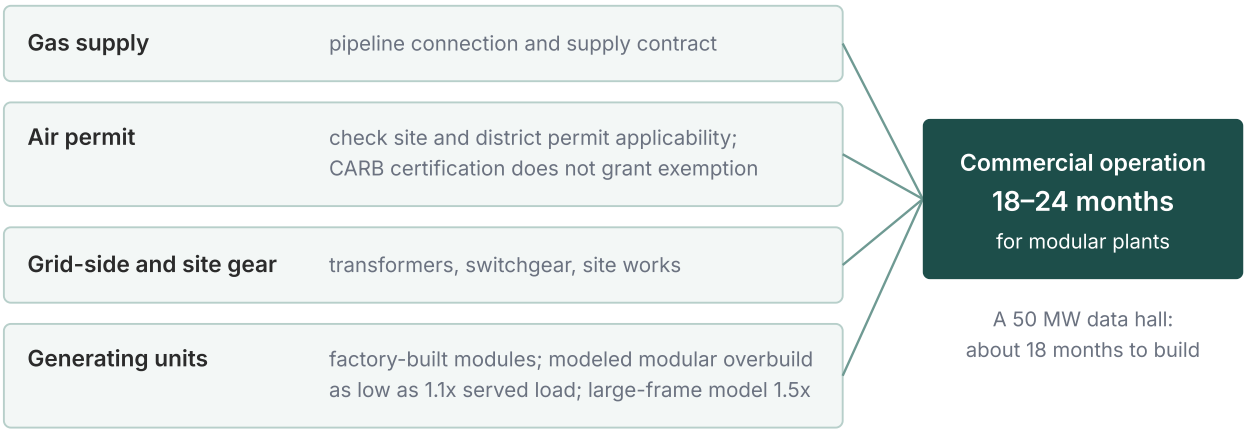
Sources: Rystad Energy (June 2026); NRG calculation

05 · THE MODULAR ROUTE

On-site projects wait on gas, permits and switchgear as much as on generators.

Enverus's modular-project estimate is 18–24 months. Generators are one track; gas service, applicable permissions and electrical works must also finish. The slowest required track sets commercial operation.

What has to finish before an on-site plant can run



Source: Enverus (August 2026); CARB DG certification program; JLL (2026)

A project still needs a deliverable gas connection and supply contract, applicable permissions, electrical works and operating tests. Equipment can arrive while another track remains unfinished. Enverus's modular deployment estimate is a project-type comparison, not a commitment that every required track clears within the same interval.

CARB's program requires certification for generating technologies already exempt from local air-district permit requirements. Certification does not itself create a universal exemption. A buyer must establish district and site applicability, other permits and operating conditions separately; a certificate for another technology cannot settle the project.

Enverus models modular engines and fuel cells with generation as low as 1.1 times served load, versus about 1.5 times for large-frame plants. That is about a quarter less nameplate per unit of load (NRG calculation), conditional on the reliability design. It is not a universal reserve ratio.

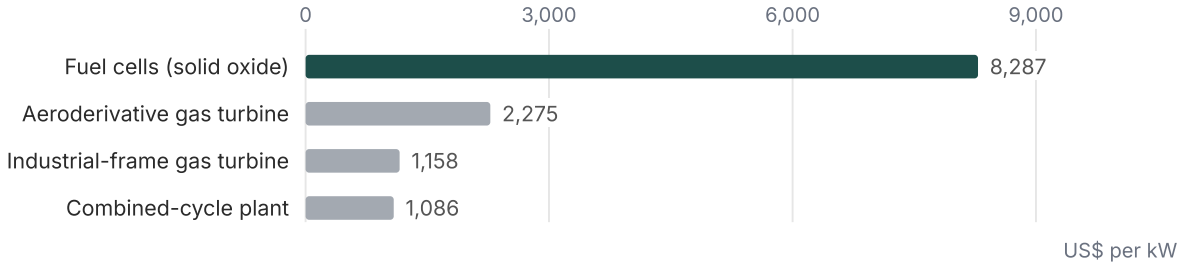
Gas access, firm supply and local transport must be checked for the actual load. Local criteria-pollutant performance and lifecycle greenhouse-gas emissions are different questions; neither alone grants permission to operate. A prepared site can exploit modular equipment more quickly, but every required site track remains in the schedule. These checks should be priced and scheduled against the same served load, including the reserve capacity and operating conditions required by the buyer.

Sources: Enverus (August 2026); CARB DG certification program; JLL (2026); NRG analysis and calculation

On EIA planning numbers, fuel cells cost four to eight times more than gas plants.

The EIA's 2026 planning assumptions put a solid oxide fuel-cell plant at $8,287 per kW to build, against $1,086–2,275 for gas plants. Part of the gap is the price of a smaller unit, and part is an allowance for early units.

Total overnight cost, US$ per kW in constant dollars of 2025; EIA planning assumptions for the Annual Energy Outlook 2026



Source: US EIA, Assumptions to AEO2026 (April 2026)

The multiple runs from about 3.6 times an aeroderivative turbine to about 7.6 times a combined-cycle plant (NRG calculation); against today's combined-cycle quotes it is nearer 3.2–3.5 times. On fuel, the fuel cell does better: its heat rate implies about 53% electrical efficiency, close to the best combined-cycle plant and well above the 36–37% of simple-cycle turbines.

At $3.48 gas and running 90% of the time, fuel plus fixed upkeep comes to about $27 per MWh for the fuel cell, against $33–34 for simple-cycle turbines and $24 for combined cycle, a saving of about $5–7 per MWh over a simple-cycle plant (NRG calculation).

The EIA number is a planning assumption for a 10 MW plant, not a site quotation. Some engineering inputs date to January 2024: translating them into 2025 dollars does not make them a 2026 market survey. DOE's 2023 class-cost status and 2030 targets use different definitions; they cannot establish today's purchase price.

The table compares different plant sizes, scopes and technology assumptions. Heat-rate efficiency is on a consistent HHV basis. Fuel plus fixed upkeep is a limited comparison: variable O&M, capital, redundant generation, degradation and extra replacements must be added for a delivered-power decision. The fuel-cell cost model includes variable O&M of $0.72/MWh.

The same EIA assumptions: size and running costs

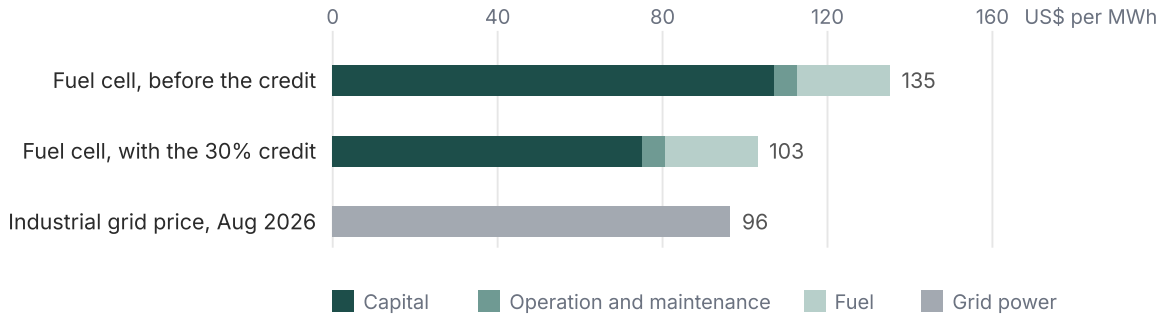
Plant	Size modelled	Heat rate, Btu per kWh	Fixed O&M, $ per kW-year
Fuel cells	10 MW	6,469	37.77
Combined cycle	627 MW	6,226	16.23
Industrial-frame turbine	419 MW	9,142	7.18
Aeroderivative turbine	211 MW	9,447	9.99

Sources: US EIA (AEO2026 assumptions, April 2026); US DOE; Rystad Energy (2026); NRG calculation

A bounded planning example gives $135/MWh before site and lifecycle additions.

The simplified case gives $103/MWh only if an assumed 30% credit is fully realized on modeled capex. August 2026 industrial grid power averaged $96/MWh; it is not a data-center tariff.

Simplified generation cost, US$/MWh; credit eligibility assumed. Site works, extra replacements and reliability additions excluded.



Source: US EIA (AEO2026; retail prices; STEO); US tax law; NRG calculation

The model uses $8,287/kW capex, an assumed 8% discount rate over 20 years and 90% running. The resulting capital-recovery factor is about 10.185%. Fixed O&M is $37.77/kW-year and variable O&M $0.72/MWh. At 6,469 Btu/kWh and $3.48/MMBtu Henry Hub forecast gas, the result is $135/MWh (NRG calculation).

At $3–6/MMBtu, it becomes $132–151/MWh, or $100–119 with the assumed credit. Delivered gas needs transport, firmness and local basis. EIA's August industrial gas average was $4.34 per thousand cubic feet, not per MMBtu; conversion requires the applicable heat content.

The credit example assumes eligible basis, construction timing, statutory qualification and realization. Fuel-cell provisions and prohibited-foreign-entity material-assistance rules require project-specific assessment. A 30% reduction on every project cost is not assured.

Capex is in constant 2025 dollars; fuel and grid inputs are 2026 nominal benchmarks. The model excludes extra stack changes, degradation, spares, gas connection and site conditioning. One generation-nameplate MW at 90% running produces 657 MWh in an assumed 730-hour month. It is not one continuously served IT MW. Facility overhead, earning utilization and who receives AI-service revenue must be reconciled; gross revenue is not margin.

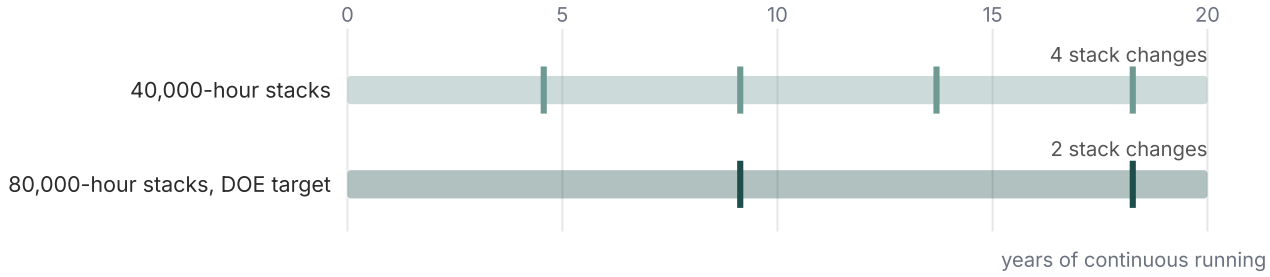
> **+$6.47/MWh**
>
> Each extra $1/MMBtu of delivered fuel adds $6.47/MWh at the modeled heat rate. Lower running raises capital cost per MWh; halving earning utilization halves assumed revenue, doubling its premium ratio (NRG calculation).

Sources: US EIA AEO2026 and August prices; October STEO; 26 USC 48E; NRG calculation

A durability benchmark illustrates replacement exposure, not AI-fleet stack life.

DOE's 2024 plan gives class-level distributed stationary durability status for 2023 and a 2030 target. Translating those operating hours into stack changes is an explicit modeling assumption, not an observed failure distribution.

Hypothetical stack changes using DOE class thresholds; 20-year plant, 100% running. At 90% duty the two counts become three and one (NRG calculation).



Source: US DOE, Hydrogen and Fuel Cell Technologies Office program plan (2024); NRG calculation

The 2023 durability range is 40,000–80,000 hours, with an 80,000-hour target for 2030. At uninterrupted running that is 4.6–9.1 years; applying those thresholds to a 20-year plant gives four or two hypothetical changes before year 20 (NRG calculation).

The graphic deliberately assumes 100% running. At the cost model's 90%, the same thresholds give three or one changes before year 20. Maintenance duration, partial repair and actual replacement scope are not modeled; the operating-hour conversion alone cannot price a service contract.

A durability threshold is not proof that every system needs a complete stack replacement when it reaches that point. DOE's class benchmarks are not a measurement of AI-site fleet performance. Degradation, maintenance availability and reserve capacity need to be evaluated together against the defined load. Service scope and the cost of scheduled downtime therefore need separate contract evidence.

The plan's ultimate 130,000-hour target is about 15 uninterrupted years, or one hypothetical change in this illustration. The older availability table gives 95% status in 2015 and a 99% target; neither is current field availability. Future targets are useful engineering markers, not guaranteed service levels.

> **88 h vs 438 h**
>
> Hours a year a unit is down at DOE's 99% availability target and at its 2015 level of 95% (NRG calculation).

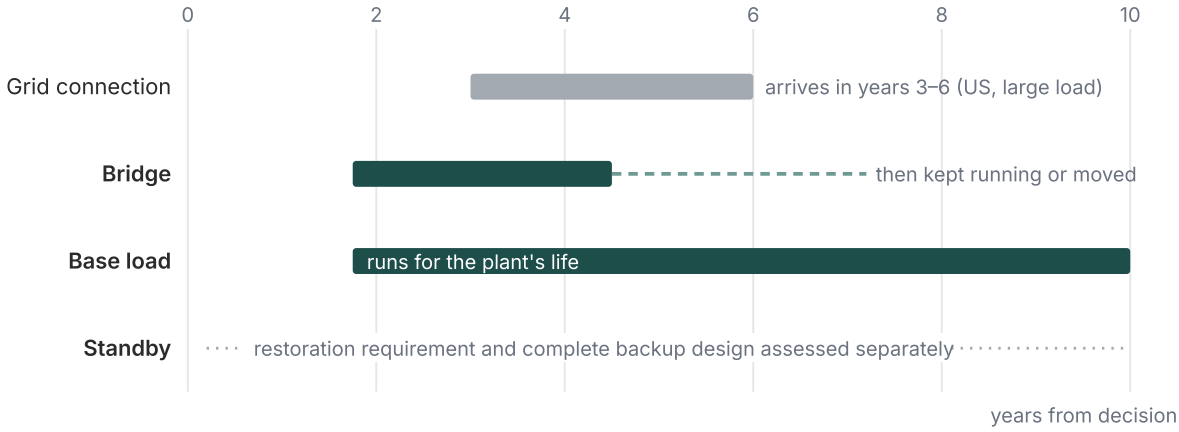
Sources: US DOE (2024 program plan; stationary fuel-cell targets; fuel-cell types); NRG calculation

09 · BRIDGE OR BASE LOAD

Steady duty can support bridge or base-load use; backup is a system question.

High-temperature SOFCs start slowly. That generally favors sustained duty. Emergency supply depends on complete architecture, stored energy, operating state and the site's restoration requirement.

How a fuel cell is used on a data-center site, in years from the decision



Source: US DOE; Rystad Energy (June 2026); Enverus (August 2026); NRG analysis

DOE identifies high temperature and slow startup as SOFC characteristics. A slowly starting unit alone cannot generally replace fast-restoring standby generation. Continuously hot or hybrid configurations require a separate engineering assessment. This report makes no universal restoration-time or code-compliance claim.

As a bridge, a modular plant could serve load after its own project completion, then remain in base-load service when the grid arrives. Applying 18–24 months and a 3–6-year grid wait gives a one-to-four-and-a-half-year bridge envelope. Those independent ranges describe a possibility, not the probability or schedule of a specific site.

JLL sees the same split for on-site gas in the United States: bridge power first, and increasingly permanent supply.

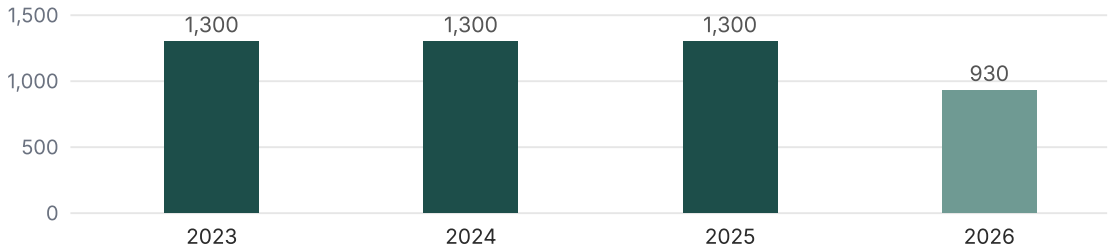
Running matters to economics. At 90% duty the model spreads capital over fewer MWh than uninterrupted operation; further idling raises unit capital cost. If the grid arrives earlier, a plant may remain useful, but the case for another bridge plant must be evaluated again rather than extrapolated.

At 90% running the illustrative bridge spans about 8,000–35,000 operating hours, below the lower 40,000-hour class benchmark. A 20-year base-load illustration at that duty implies three or one threshold changes, versus four or two in the uninterrupted graphic (NRG calculation). Actual maintenance and replacement remain site and technology dependent.

Korea's auction buys annual energy; its small winners do not set a universal cap.

The October 30, 2026 official opening offers 930 GWh a year in general hydrogen and a separate 500 GWh in clean hydrogen. These are contract-energy volumes, not equipment shipments or currently operating MW.

General-hydrogen auction volume offered, GWh a year



Source: Historical auction reporting (2023–2025); official October 30, 2026 opening

The 2025 official results show 52 awards totaling 1,355 GWh a year from 77 bids totaling 3,137 GWh. All winning plants were 20 MW or smaller. That describes the award distribution for that round; it does not establish a permanent eligibility ceiling on every procurement route.

The new general-market round is about 72% of the earlier 1,300 GWh annual offer. A smaller energy volume is not direct evidence of factory utilization, because capacity factor, chemistry, project timing and other markets differ.

General-market selection is expected in December 2026, with operation by 2029 and a 20-year trading period. Clean-market selection is expected in June 2027, with operation by 2030 and a separate 15-year trading period. The opening also strengthens environmental evaluation, including carbon-capture and utilization/storage plans.

At an assumed 85% capacity factor, 930 GWh a year corresponds to about 125 MW. A different implied factor gives a different MW number, so energy is the primary statistic. The auction is a national annual-energy procurement; a developer still needs to establish how a lawful supply arrangement serves its particular site and load. It cannot infer a campus contract simply by converting the auction total into equipment capacity.

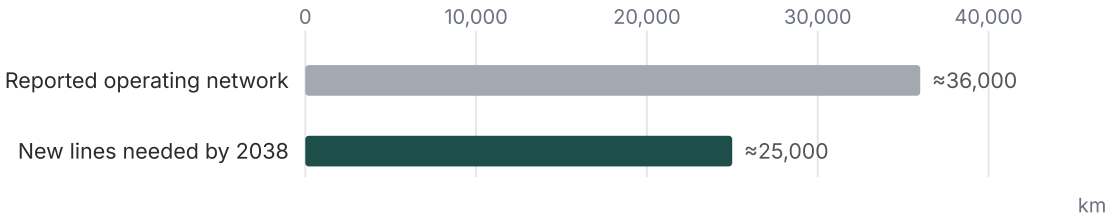
> **≈125 MW**
>
> 930,000 MWh / (8,760 hours × 85% assumed capacity factor). Public-input conversion, not awarded or operating capacity (NRG calculation).

Sources: Official Korean auction results (August 2025); official opening (October 2026); historical auction reporting; NRG calculation

Korea has direct-trading routes; eligibility and commercial fit remain site-specific.

The designated-zone direct-trading notice effective June 23, 2026 provides a contract route. It does not establish that every data center, region or supply arrangement qualifies or can secure dependable power at a workable price.

Korea: transmission lines in operation and to be added by 2038, km



Source: Metro Seoul (October 2026), citing the national utility

An October 2026 press account of the utility's transmission plan reports about 25,000 km of additions by 2038 against about 36,000 km in operation, roughly 70%. The underlying complete utility plan was not recovered for this revision; these remain attributed historical press figures, not newly verified current utility statistics.

The same account gives about 78.7 GW of data-center applications, including duplicates, and about 8.4 GW of specific AI supply requests. Applications do not equal realized load. Its nine-year overhead-line example and roughly four-year underground example have different scope; neither is an individual connection promise.

Direct trading within designated distributed-energy zones is separate from the general-hydrogen auction. Region, participant eligibility, supply arrangements and applicable operating rules need to fit the site. A district-electricity supplier's capacity category is also separate; it cannot be applied as a universal cap on all on-site generation.

A legal route's existence does not prove its scale, price, firm fuel availability or project economics. Conversely, small auction winners do not establish legal impossibility. NRG's analysis therefore uses conditional readiness: a viable procurement route, dependable delivered power and lifecycle economics must meet together. Fuel-cell factories alone cannot establish demand, but neither can the absence of a purpose-built auction prove that buyers have no options.

Separate gates

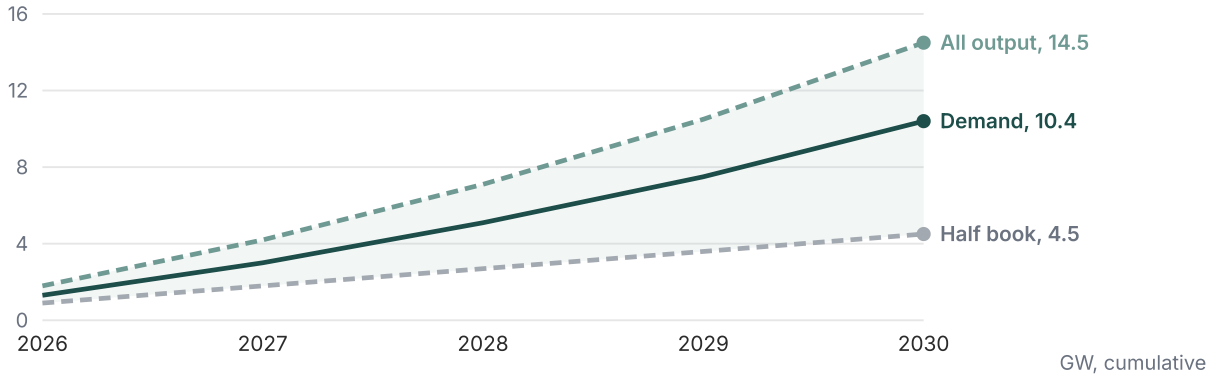
Procurement eligibility, site permission and dependable delivered-power economics must each be checked. A contract route is not proof of a commercially viable site.

Sources: Direct-trading notice effective June 23, 2026; Metro Seoul (October 2026), attributed utility figures; NRG analysis

Calendar 2026–2030 supply arithmetic is not an installation forecast.

This illustration uses five calendar buckets, including largely elapsed 2026. Manufacturing output, demand and commissioned capacity are different stages. No actual 2026 installation total or five-forward-year forecast is inferred.

Public-input illustration over calendar 2026–2030, cumulative GW. Assumed output/allocation, not observed installations; all-in-year conversion is unverified.



Source: Rystad Energy (2026); NRG calculation

ALL-OUTPUT ILLUSTRATION	14.5 GW	Assume annual manufacturing of 1.8, 2.35, 2.9, 3.45 and 4.0 GW; sum all output. No other uses, inventory or site delay. Not installed capacity.
DEMAND COMPARATOR	10.4 GW	Rystad's 10.4 GW demand comparator is about 72% of the output sum. The line allocates that fraction to each calendar bucket; not observed annual demand or installation.
HALF-BOOK ILLUSTRATION	4.5 GW	Assume half the 9 GW mixed book converts, spread evenly at 0.9 GW per calendar bucket. A chosen fraction and timing, not an empirical cancellation rate or forecast bound.

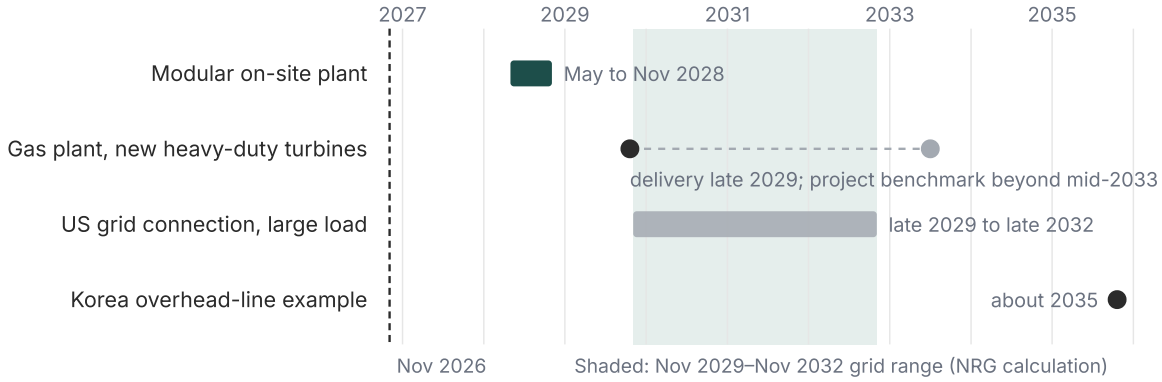
SIGNPOSTS

- Framework conversion to firm purchases, shipments and commissioned load
- Disclosed duty, maintenance and dependable served-load performance
- Manufacturing ramp, yield and allocation to other applications
- Actual site fuel, permissions and grid-service dates

Applying source ranges to November 2026 gives conditional landing dates.

This is calendar arithmetic, not a site schedule. Modular completion, heavy-duty turbine delivery, full gas-plant operation and grid connection are distinct endpoints. The shaded grid band matches the dated grid bar.

When power arrives for a decision made in November 2026; the shaded band is the grid-arrival window (NRG calculation)



Source: Enverus via Power Engineering (2026); Rystad Energy (2026); company filings and announcements; Metro Seoul (2026); NRG calculation

ON-SITE MODULAR	May–Nov 2028	Add 18–24 months to November 2026. Gas, permissions and site works must be ready; a tax-credit outcome remains conditional on eligibility and realization.
NEW GAS PLANT	Separate endpoints	A dated three-year delivery marker lands in late 2029. Adding Enverus's more-than-80-month combined-cycle benchmark puts project operation beyond mid-2033. Distinct source endpoints, not a COD range.
GRID CONNECTION	Nov 2029–Nov 2032	Add Rystad's 3–6-year large-load grid range to November 2026. The shaded interval uses the same endpoints (NRG calculation), without a universal clearance date.

SIGNPOSTS

- Firm orders versus reservations and actual manufacturing shipments
- Eligible capex, statutory credit conditions and actual realization
- Operating share of dated announced-project snapshots
- Korean procurement eligibility, firm supply terms and site readiness

Sources: Enverus; Rystad Energy; company filings; Cleanview; Metro Seoul (2026); US tax law; NRG calculation

METHOD

How this report was built.

Public sources were checked on November 5, 2026. Original publication was November 2, 2026. The evidence combines IEA April demand and October policy reports; DOE/LBNL's 2025 Update released June 2026; EIA planning, fuel and retail series; CARB's program description; official Korean auction and direct-trading records; market researchers; dated press accounts; and public filings. Historical benchmarks retain their observation years. Access-limited methods and unresolved primary coverage are not certified as latest or complete.

An NRG estimate is a safely generalized research range checked against public evidence. This report carries no NRG estimate; every figure is public or an NRG calculation. NRG's own research shaped general questions about readiness, operating duty and lifecycle cost; numerical claims use public evidence.

An NRG calculation derives only from public inputs. The generation model uses an assumed 8% discount rate over 20 years and 90% running, with fixed and variable O&M. It mixes constant-2025-dollar capex and nominal-2026 benchmarks for illustration; it excludes additional stack replacements, degradation, spare generation and site/fuel works. The assumed credit requires eligible basis and realization. Gross AI revenue is not margin; IT, facility and nameplate MW must be reconciled.

The uninterrupted stack illustration uses 100% running; the cost case uses 90%, with different hypothetical replacement counts. The calendar 2026–2030 supply illustration is not a five-forward-year installation forecast. Landing dates are arithmetic applied to separate source ranges, not project commitments. Public paid-model detail, full site costs and site-specific regulatory applicability were not established.

Companies are described rather than named. General mechanisms are NRG analysis, not claims about a particular company. This is business and market research, not investment advice.

WORKING WITH NATHAN RESEARCH GROUP

Partner With Nathan Research Group

Public forecasts and auction results show interest and procurement volumes. Site decisions also require a clear view of fuel service, permissions, equipment delivery and dependable operation. We connect teams with people who understand those decisions through a compliant research process.

WHO WE PUT IN THE ROOM

Data-center power and energy leads	Owner and developer teams who choose between grid, turbines and fuel cells for new AI data centers.
Utility and interconnection specialists	Large-load connection queues in the US and Korea's grid-impact review for new data-center demand.
On-site generation engineers	Design, operation and maintenance of fuel cells, engines and turbines on data-center sites.
Equipment supply specialists	Lead times and delivery for turbines, fuel cells, transformers and switchgear.
Gas supply and permitting specialists	Pipeline capacity, air permits and local siting rules for on-site generation.
Energy policy and market specialists	Korea's hydrogen-power auctions and power-market rules, and US state policy on large new loads.

If your team is evaluating solid oxide fuel cells, the on-site power market for AI data centers, or the broader fuel-cell and distributed-power sector, tell us the decision you're trying to make.

START THE CONVERSATION

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Based on public sources and NRG's own research. Figures marked NRG estimate are rounded ranges checked against public data. Nathan Research Group does not request or facilitate material non-public information, and runs every engagement through a documented compliance protocol.